4. Project Economics and Financing

Chapter Overview

Evaluating the economic feasibility of various landfill gas (LFG) energy project options, selecting the most viable alternative, and determining available financing for the project are integral steps in the project development process. This chapter provides guidance on the steps for performing an economic analysis and discusses the various financing alternatives available for LFG energy projects. This chapter includes:

- Information on typical capital and operation and maintenance (O&M) costs for LFG collection systems, LFG electricity projects, and direct-use projects, and discussion of factors that influence these costs.
- Information on potential revenue streams, financial incentives, and funding opportunities for LFG energy projects.
- Examples of preliminary financial evaluations of LFG energy projects.
- References to online documents and tools for further information.
- Discussion of project financing options.

Economic Evaluation Process

The first step in the evaluation process is to perform a preliminary economic feasibility assessment. This assessment will help determine if a project is right for the landfill in question, and if so, what project configuration should be considered in the next phases of evaluation. EPA's Landfill Methane Outreach Program (LMOP) provides the LFGcost-Web economic assessment tool to help Partners perform preliminary cost assessments. LMOP can also provide assistance in customizing preliminary LFGcost analyses.

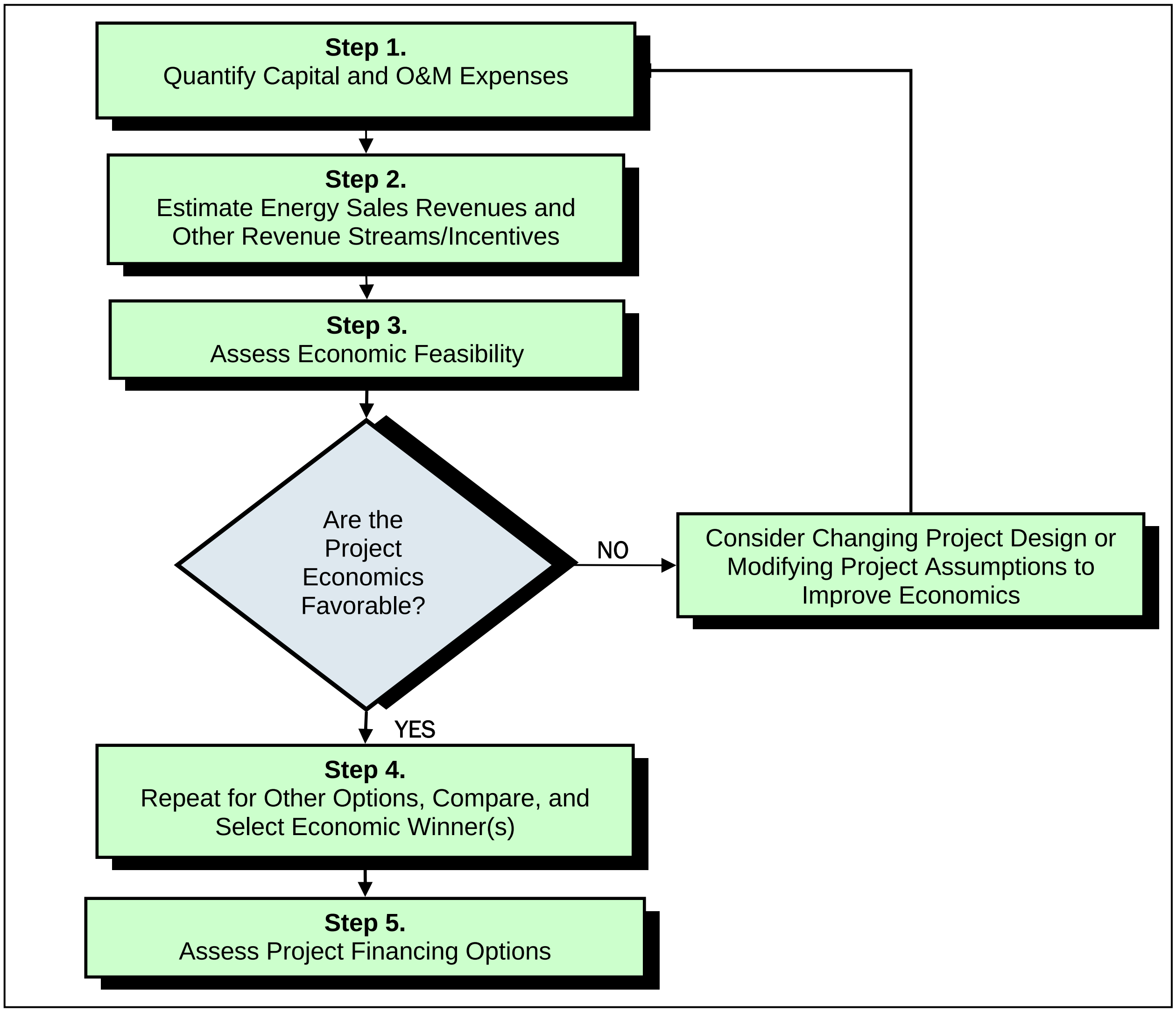
If the preliminary economic assessment shows that a project may be well-suited to the landfill, then a detailed economic assessment tailored to the landfill and potential project options should be performed. This feasibility assessment will often require the assistance of a qualified LFG professional engineering consultant or project developer. The detailed economic assessment is an essential step before preparing a system design, entering into contracts, or purchasing materials and equipment for the project.

The steps taken in both the preliminary and detailed economic feasibility assessments are similar, but the site-specific detail is different. For example, a preliminary feasibility study is based on *typical* costs (e.g., typical equipment costs, typical right-of-way and permitting costs, typical financing methods and interest rates). A detailed feasibility study, on the other hand, is based on *project-specific* costs and estimates (e.g., cost quotes for a specific model of equipment appropriate to the landfill, assessment of right-of-way costs depending on pipeline routes and number of land owners, assessment of permitting costs depending on state-specific permitting requirements, specific financing methods and interest rates). In both cases, the outputs of these assessments include costs and measures of financial performance required to make investment decisions, such as:

- Total installed capital costs
- Annual costs in first year of operation
- Internal rate of return (IRR)
- Payback period
- Net present value (NPV)

The economic assessment process typically includes five steps, as shown in Figure 4-1. The following sections discuss these five steps and provide helpful links, examples, and resources to aid in the evaluation process.

Figure 4-1. The Economic Evaluation Process



4.1 Step 1: Quantify Capital and O&M Costs

LFG energy project costs may include costs for gas collection and flaring, electricity generation, direct use, or other project options. Generally speaking, each LFG energy project will involve the purchase and installation of equipment (capital costs) and the expense of operating and maintaining the project (O&M costs). Cost elements common to various LFG energy projects are listed below, and the following sections describe in more detail specific factors that may influence the project costs and typical cost ranges for the more common project types.

Capital (i.e., equipment) costs include:

- Design and engineering and administration
- Permits and fees
- Site preparation and installation of utilities
- Equipment, equipment housing, and installation
- Startup costs and working capital

O&M cost elements include:

- Parts and materials
- Labor
- Utilities
- Financing costs
- Taxes
- Administration

Gas Collection System and Flaring Costs

One necessary component of an LFG energy project is the gas collection and flare system. This equipment gathers the LFG for combustion in the project's flare, electricity-generating equipment, or direct-use device, and provides a way to combust the gas when the project is not being operated. The collection system and flaring costs should be included as project costs only if these systems do not currently exist at the landfill. If a gas collection and flare system exists, it represents a "sunk" cost and the project costs need only include modifications to the system to tie in project equipment.

A mid-sized LFG collection and flare system for a 40-acre wellfield designed to collect 600 cubic feet per minute (cfm) is approximately $991,000, or $24,000 per acre, for installed capital costs, with average annual O&M costs of around $166,000 or $4,100 per acre.[1] These costs can vary depending on several design variables of the gas collection system. The gas collection and flare system components and key factors that influence the costs of these components are listed below:

[1] LFGcost-Web V2.0 at http://www.epa.gov/lmop/res/index.htm#5a. September 9, 2009.

- Gas collection wells or collectors (key factors: area and depth of waste, spacing of wells or collectors).

- Gas piping (key factors: gas volume, length of piping required).

- Condensate knockout drum (key factor: volume of drum required).

- Blower (key factor: size required).

- Flare (key factors: flare type — enclosed or open, ground or elevated — and size).

- Instrumentation and control system.

It is important to decide early on whether to collect gas from the entire landfill or just the most productive area. Note that this decision may be dictated in some cases by regulatory requirements to collect gas. It is often most cost-effective to put in a smaller collection system first and then extend the system over time as new areas are filled and begin to produce significant quantities of gas. This approach has the added benefit of creating multiple systems that run in parallel, thereby allowing the project to continue operating at reduced capacity when a piece of equipment (e.g., a blower) is temporarily out of service.

Electricity Project Costs

The most common technology options available for developing an electricity project are internal combustion engines, gas turbines, microturbines, and small engines. Each of these technologies is generally better suited to certain project size ranges, as shown in Table 4-1. For example, small internal combustion engines and microturbines are generally best suited for small or unique power needs. Standard internal combustion engines are well-suited for small- to mid-size projects, whereas gas turbines are best suited for larger projects. A few boiler/steam turbine systems are also in operation at very large landfills (e.g., for 30–50 megawatt [MW] projects). Furthermore, if there is a use for the heat produced from the combustion of the LFG in the electricity-generating equipment, then a combined heat and power (CHP) project may be a preferable option. CHP systems are discussed in the “Other Project Options” section of this chapter.

Because project LFG flow changes over the life of the project, it is important to decide whether to size equipment for minimum flow, maximum flow, or average flow. This may help determine which technology is best suited for the project. Due to the high capital cost of electricity generating equipment, it is often advantageous to size the project at (or near) the minimum gas flow expected during the 15-year project life. This approach, however, can result in lost opportunity to generate electricity and receive revenues in years when gas is more plentiful. The best sizing approach for the project will largely be influenced by the site-specific gas curve, electricity rate structures, other revenue streams, and contract obligations (i.e., minimum electricity generation requirements). It may be worth evaluating the economics of sizing near the minimum and near the maximum gas flow. Also consider adding generating capacity (more internal combustion engines or gas turbines) over time as flow from the landfill increases.

For a basic electricity project, the costs associated with the project involve purchasing, installing, and operating/maintaining several components:

- Gas compression and treatment to condition LFG for use in the internal combustion engine or turbine.
- Internal combustion engine/gas turbine and generator set to generate the electricity.
- Interconnect equipment which is necessary for adding electricity to the grid.

For further discussion of LFG treatment and electricity project technologies, see Chapter 3.

As a guide to start a preliminary assessment, Table 4-1 lists some typical costs and applicable LFG energy project sizes for the most common electricity generation technologies. These costs include costs for the electricity generation equipment as well as costs for typical compression and treatment systems appropriate to the particular technology and interconnection equipment. Treatment costs, however, can vary widely depending on whether siloxane removal or other treatment is required. Interconnection costs can vary depending on project size and utility policies and requirements. For further information on interconnection, see the EPA CHP Partnership's Interconnection Web page.

Table 4-1. LFG Electricity Project Technologies — Cost Summary

Technology	Optimal Project Size Range	Typical Capital Costs ($/kW)*	Typical Annual O&M Costs ($/kW)*
Microturbine	1 MW or less	$5,500	$380
Small internal combustion engine	1 MW or less	$2,300	$210
Large internal combustion engine	800 kW or greater	$1,700	$180
Gas turbine	3 MW or greater	$1,400	$130

* 2010 dollars.
kW: kilowatt
MW: megawatt

Example preliminary economic assessments for a 3 MW internal combustion engine electricity project are presented in Appendix 4-A. These case studies can provide an idea of typical inputs, assumptions, and outputs expected from a preliminary economic assessment. LMOP provides assistance in performing preliminary economic assessments of these technologies with its LFGcost-Web tool available to LMOP Partners. Before moving forward, however, a more detailed site-specific analysis will be needed.

Direct-Use Project Costs

A direct-use project may be a viable option if an end user is located within a reasonable distance of the landfill. Examples of direct-use projects include industrial boilers, process heaters, kilns, furnaces; or space heating for commercial, industrial, or institutional facilities or for greenhouses.

For direct-use projects, costs may vary depending on the end user's requirements, but will typically involve the following items:

- Gas compression and treatment to condition gas for the end user's equipment
- A gas pipeline to transport LFG to the end user
- A condensate management system for removing condensate along the pipeline

The size of the pipeline can affect project costs. For projects with increasing gas flow over time, it is often most cost-effective to size the pipe at or near the full gas flow expected during the life of the project and to add compression and treatment equipment as gas flow increases.

Table 4-2 lists typical cost ranges for the components of a direct-use project. The costs shown below for the gas compression and treatment system include compression, moisture removal, and filtration equipment typically required to prepare the gas for transport through the pipeline and for use in a boiler or process heater. If more extensive treatment is required to remove other impurities, costs will be higher. The gas pipeline costs also assume typical construction conditions and pipeline design. Pipelines can range from less than a mile to over 20 miles long, and length will have a major effect on costs. In addition, the costs of direct-use pipelines are often affected by obstacles along the route, such as highway, railroad, or water crossings.

Table 4-2. LFG Direct-Use Project Components — Cost Summary

Component	Typical Capital Costs*	Typical Annual O&M Costs*
Gas compression and treatment	$960/scfm	$90/scfm
Gas pipeline and condensate management system	$330,000/mile	Negligible

* 2010 dollars, based on a 1,000 scfm system.
scfm: standard cubic feet per minute

End users will likely need to modify their equipment to make it suitable for combusting LFG, but these costs are usually borne by the end user and are site-specific to their combustion device. Landfill owners or LFG energy project developers may need to inform the end user that they are responsible for paying for these modifications, noting that modification costs are normally minimal and the savings typically achieved by using LFG will more than make up for any equipment modification expenses. LMOP has developed a boiler retrofit fact sheet to help potential end users understand what types of modifications may be needed to use LFG in a boiler. The fact sheet also provides several examples of where LFG has been used in boiler fuel applications. Additional case studies for LFG uses at industrial and commercial sites are also available.

Example preliminary economic assessments for a typical direct-use project (in this case, 1,000 cfm LFG) with either a 5- and 10-mile pipeline are presented in Appendix 4-B. These case studies can provide ideas about typical inputs, assumptions, and outputs expected from a preliminary economic assessment.

Other Project Options

In addition to electricity and direct-use projects, other less common LFG energy project options exist, including CHP, leachate evaporation, vehicle fuel, and upgrading to high-Btu gas for sale to natural gas companies. These technologies are not as universally applicable as the more traditional LFG energy projects, but given the right situation, they can be very cost-effective and may be worth exploring as potential project options.

CHP involves capture and use of the waste heat produced by electricity generation. These projects are gaining momentum, as they provide maximum thermal efficiency from the collected LFG. Since the steam or hot water produced by a CHP project is not economically transported long distances, CHP is a better option for end users located near the landfill, or for projects where the LFG is transported to the end user's site and both the electricity and the waste heat is generated at their site. The electricity produced by the end user can be used on site or sold to the grid. EPA's CHP Partnership provides additional discussion on various CHP technology options available to LFG and other biomass projects.

Leachate Evaporators combust LFG to evaporate most of the moisture from landfill leachate, thus greatly reducing the leachate volume and subsequent disposal cost. These projects are cost-effective in situations where leachate disposal in a publicly owned treatment works or wastewater treatment plant is unavailable or very expensive.

Vehicle Fuel Applications involve the production of compressed natural gas (CNG), liquefied natural gas (LNG), or methanol. This process involves removing methane and other trace impurities from LFG to produce a high-grade fuel that is approximately 95 percent methane or greater. Currently, CNG and LNG vehicles make up a very small portion of motor vehicles in the United States, so there is not a large demand for these vehicle fuels. With interest in alternative fuels continuing to grow, demand is expected to increase. Furthermore, landfill owners/operators can achieve cost savings if these fuels can be used for the landfill's truck fleets. Costs associated with this option include converting the vehicles to use the alternate fuel and installing a fueling station.

To Upgrade LFG to Produce High-Btu Gas, a variety of technologies, described in Chapter 3, can be used to separate the methane and carbon dioxide components of LFG to provide methane for sale to natural gas suppliers or for use in applications requiring a high-Btu fuel. Although expensive, increasing energy costs may make high-Btu gas a more viable option. These projects are ideally suited for large landfills located near natural gas pipelines.

CHP, leachate evaporation, and high-Btu project assessments are included as options in LFGcost-Web (for Partners). LMOP can assist with preliminary economic analyses for these technologies.

4.2 Step 2: Estimate Energy Sales Revenues and Other Revenue Streams or Incentives

Electricity Project Revenues

The primary revenue component of the typical electricity project is the sale of electricity to the local utility. This revenue stream is affected by the electricity buy-back rates (i.e., the rate at which the local utility purchases electricity generated by the LFG energy project). Electricity buy-back rates for new projects depend on several factors specific to the local electric utility and the type of contract available to the project, but typically range between 4 and 11 cents per kilowatt-hour (kWh).[2, 3, 4] The upper end of this range represents premium pricing for renewable electricity. Occasionally, the electricity is sold to a third party at a rate that is attractive when compared to the local retail electricity rates. When assessing the economics of an electricity project, it is also important to consider the avoided cost of the electricity used on site. Electricity generated by the project that is used in other operations at the landfill is, in effect, electricity that the landfill does not have to purchase from a utility. This electricity is not valued at the buy-back rate, but at the rate the landfill is charged to purchase electricity (i.e., retail rate). The retail rate is often significantly higher than the buy-back rate.

LFG energy projects can potentially use a variety of additional environmental revenue streams, which typically take advantage of the fact that LFG is recognized as a renewable, or "green," energy resource. These additional revenues can come from premium pricing, tax credits, greenhouse gas credit trading, or incentive payments. They can be reflected in an economic analysis in various ways, but typically, converting to a cents/kWh format is most useful. LFGcost accommodates four common types of electric project credits: a direct cash grant, a renewable energy tax credit expressed in dollars per kWh, a direct greenhouse gas (carbon) credit expressed in dollars per metric ton of carbon dioxide equivalent, and a direct electricity tax credit expressed in dollars per kWh. The following list includes the available environmental revenue streams that an LFG energy project could possibly use.

- Premium pricing is often available for renewable electricity (including LFG) that is included in a green power program, through a Renewable Portfolio Standard (RPS), a Renewable Portfolio Goal (RPG), or a voluntary utility green pricing program. These programs could provide additional revenue above the standard buy-back rate because LFG electricity is generated from a renewable resource. The LMOP online funding guide features a list of states with RPS or RPG that include LFG energy. The National Renewable Energy Laboratory provides green power pricing lists that show utilities and power providers that are using LFG and in which states these products are available.

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[2] U.S. EPA Landfill Methane Outreach Program. 2007. *An Overview of Landfill Gas Energy in the United States.*

[3] Michels, M. 2008. Telephone call between M. Michels, Cornerstone Engineering, and C. Burklin, ERG. (June 15, 2008). Re: Typical prices for sale of electricity and LFG from LFG energy projects.

[4] U.S. DOE Energy Information Administration. 2008. Average Wholesale Price Table. http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html and http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesalet2.xls

- Renewable energy certificates (RECs) are sold through voluntary markets to consumers seeking to reduce their environmental footprint. They are typically offered in 1 megawatt-hour (MWh) units, and are sold by LFG electricity generators to industries, commercial businesses, institutions, and even private citizens who wish to achieve a corporate renewable energy portfolio goal or to encourage renewable energy. If the electricity produced by an LFG energy project is not being sold as part of a utility green power program or green pricing program, the project owner may be able to sell RECs through voluntary markets to generate additional revenue. There are certification programs for RECs to be sure the amount of electricity generated can be verified and renewable attributes of electricity are not sold twice. EPA's Green Power Partnership provides a state-by-state directory of green power providers in its Green Power locator.

- Tax credits, tax exemptions, and other tax incentives, as well as federal and state grants, low-cost bonds, and loan programs are available to potentially provide funding for an LFG energy project. For example, Section 45 of the Internal Revenue Code provides a per-kWh federal production tax credit for electricity generated at privately owned LFG electricity projects. To qualify for the credit, which was 1.1 cent per kWh for the 2009 taxable year, all electricity produced must be sold to an unrelated person during the taxable year. Under legislation passed in February 2009, the placed-in-service date deadline for LFG energy projects to be eligible for the first 10 years of production is December 31, 2013. Another popular funding option is the Clean Renewable Energy Bond (CREB) program, which allows electric cooperatives, government entities, and public power producers to issue bonds to finance renewable energy projects including LFG electricity projects. The borrower pays back the principal of the CREB, and the bondholder receives federal tax credits in lieu of the traditional bond interest. More details about these incentives can be found in LMOP's online funding guide. This document is updated quarterly with the latest information on a wide range of available tax credits and incentive programs applicable to LFG energy projects. Additionally, LMOP developed "Federal Incentives for Developing Landfill Gas Energy Projects" to summarize key provisions of the American Recovery and Reinvestment Act of 2009 and other federal incentives that are most likely to support LFG energy development.

- Many state and regional government entities are establishing their own greenhouse gas initiatives to cap or minimize greenhouse gas emissions within their jurisdictions. Examples include the Regional Greenhouse Gas Initiative (RGGI), the Washington carbon dioxide offset program, and the Massachusetts carbon dioxide reduction from new plants. Some of these programs establish a cap-and-trade program on carbon dioxide emissions, while others require new fossil-fueled boilers and power plants to either implement or contribute to funding of offset projects, such as LFG energy. Programs may have certain size restrictions or qualification requirements, so it is necessary to ask the state government whether it participates in such a program and what the requirements may be. See the EPA document "Environmental Revenue Streams for CHP and Biomass Projects" for additional information.

- Certain LFG energy projects may qualify for participation in nitrogen oxides cap-and-trade programs, such as the nitrogen oxides State Implementation Plan (SIP) call. The revenues for these incentives vary by state and will depend on factors such as the allowances allocated to each project, the price of allowances on the market, and if the project is a CHP project (typically CHP projects receive more revenue due to credit for avoided boiler fuel use). In the past, prices have ranged from $500 to $7,000 per ton of nitrogen oxides,[5] with the 2007

[5] U.S. EPA and Ozone Transport Commission. 2003. *OTC NO_x Budget Program — 1999–2002 Progress Report.* http://www.epa.gov/airmarkets/progress/docs/otcreport.pdf

prices being near $1,000/ton.[6] See the EPA document “Environmental Revenue Streams for CHP and Biomass Projects” for additional information.

- LFG energy projects are also well suited to voluntary emissions trading programs. The Chicago Climate Exchange (CCX) offers a credit of 18.25 metric tons of carbon dioxide per metric ton of methane combusted. In the past, prices offered have ranged from $1 to $7 per metric ton of carbon dioxide equivalent. The credit includes certain restrictions based on project start dates; also, if the landfill is required by law to collect and combust LFG, then it cannot receive credit for methane reductions. In addition to methane reduction offsets, LFG energy projects that produce electricity may also qualify for CCX emission offsets for renewable energy as long as the RECs are not being sold elsewhere. To learn more about the CCX program and to find out if a project might be eligible, see the CCX Web site.

- Bilateral trading and greenhouse gas credit sales are other voluntary sources of revenue. Unlike the CCX, bilateral trades are project-specific and are negotiated directly between a buyer and seller of greenhouse gas credits. In these cases, corporate entities or public institutions, such as universities, may wish to reduce their “carbon footprint” or meet internal sustainability goals, but do not have direct access to developing their own project. Therefore, a buyer may help finance a specific project in exchange for the credit of offsetting greenhouse gas emissions from their organization. These may be simple transactions between a single buyer and seller (e.g., the project developer), or may involve brokers that “aggregate” credits from several small projects for sale to large buyers.[7] Similar to certification programs for RECs, voluntary and bilateral trading programs often involve certification and quantification of greenhouse gas reductions to ensure validity of the trade. As a result, there can be rigorous monitoring and recordkeeping requirements for participating in the program. The additional revenue, however, is likely to justify these additional efforts.

Direct-Use Project Revenues

The primary source of revenue for direct-use projects is the sale of LFG to the end user; the price of LFG, therefore, dictates the projects’ revenues. Often LFG sales prices are indexed to the price of natural gas (e.g., 70 percent of the NYMEX or Henry HUB natural gas price indices) [8], but prices will vary depending on site-specific negotiations, the type of contract, and other factors. In recent years, typical LFG prices have ranged from $4.00 to $8.00 per million British thermal units (MMBtu) or 0.38¢ to 0.75¢ per megajoule. (Chapter 5 contains additional information about factors that can affect LFG pricing.) In general, the price paid by the end user must provide an energy cost savings that outweighs the cost of required modifications to boilers, process heaters, kilns, and furnaces in order to burn LFG. The LMOP LFG boiler retrofit fact sheet illustrates the modifications potentially needed to burn LFG and presents several examples of effective direct-use projects.

Federal and state tax incentives, loans, and grants are available that may provide additional revenue for direct-use projects. The LMOP online funding guide presents updated information on available

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[6] Argus Air Daily. April 19, 2007. Volume 14.

[7] SCS Engineers. 2007. *Carbon Credits Bilateral Markets a.k.a. Voluntary Offset or Over-the-Counter Markets.* Presented at the PWIA Fall Conference, September 6, 2007.

[8] Michels, M. 2008. Telephone call between M. Michels, Cornerstone Engineering, and C. Burklin, ERG. (June 15, 2008). Re: Typical prices for sale of electricity and LFG from LFG energy projects.

incentives and how to qualify for them. Greenhouse gas emissions trading programs, such as the CCX, are also potential revenue streams for direct-use projects.

LMOP's online support software, LFGcost-Web, accommodates three common types of direct LFG use credits: a direct cash grant, a renewable energy tax credit expressed in $/MMBtu, and a direct greenhouse gas reduction credit expressed in $/metric ton of carbon dioxide equivalent. Note that the renewable energy tax credit is available only to private entities that pay taxes.

Lancaster County Solid Waste Management Authority (LCSWMA) — Selling Emission Offsets on the Chicago Climate Exchange[9]
In 2005, LCSWMA and PPL Energy Services formed a partnership to develop a project that extracts methane from the Creswell and Frey Farms Landfills to generate both electricity and steam (CHP). LCSWMA voluntarily installed the gas collection wells and pipeline. PPL owns the energy generation plant that is located next to Turkey Hill Dairy. PPL buys LFG from LCSWMA. They use two internal combustion engines to generate electricity to sell into the regional grid. The waste heat from the internal combustion engines is used to produce steam, which is sold to the dairy, providing 80 percent of the dairy's steam needs and reducing the dairy's fuel costs. LCSWMA realizes significant revenues from the sale of greenhouse gas offsets. They were the first public environmental services authority to join and sell carbon dioxide emission offset credits generated from LFG on CCX. LCSWMA meets CCX offset project criteria because they own the LFG recovery system, installed it voluntarily after the specified date, and have ownership of the carbon dioxide emission offsets. LCSWMA expects to sell up to 80,000 metric tons of carbon dioxide equivalent per year, and anticipates up to $300,000 per year in revenue. Prices in late 2006 were near $4/metric ton. Prices on CCX had fallen to $0.20/metric ton by August 2009. LCSWMA listed this project on the Climate Action Reserve (CAR) and is in the process of verifying and registering additional carbon dioxide emission offset credits to sell to the voluntary carbon market. The revenue from these carbon credit sales is helping LCSWMA rapidly pay back its gas collection system installation costs.

4.3 Step 3: Assess Economic Feasibility

Once the costs and revenues for a project have been determined and if the project is still considered viable, an economic feasibility analysis should be performed. LMOP Partners can use LFGcost-Web to perform the preliminary economic feasibility. When performing a more detailed analysis, however, many LFG energy consulting companies and LFG energy project developers rely on their own financial pro forma programs, which may enable a more detailed analysis for a specific project. This financial pro forma is a spreadsheet model to estimate cash flow based on the costs and revenue streams, and it provides a more accurate estimate of the probable economic performance over the lifetime of the project. To perform this analysis, calculate and compare the expenses and revenue on a year-by-year basis for the life of the project. Several elements must be input into the model, most of which can be obtained from LFGcost (or a more detailed site-specific cost analysis) and an analysis of the revenue streams:

- Project capital and O&M cost data.

[9] Lancaster County Solid Waste Management Authority. 2007. *Selling Landfill Gas Emission Offsets on the Chicago Climate Exchange.* Presented at the 2007 LMOP Conference, Baltimore, Maryland, January 23, 2007.

- Operation summary — electricity generated, Btu delivered, gas consumed.
- Financing costs — the amount of the project that is financed and the interest rate will determine how much it will cost to service the project's debt each year.
- Inflation rates — this could impact O&M costs, especially if the product is sold at a fixed price over a term.
- Product price escalation rates — increases or decreases in the price of electricity or LFG will affect project revenues.
- Revenue calculation — sales of electricity and incentive/markets revenue.
- Cost uncertainty factors — the project capital or O&M costs may be less or more than expected in any given year.
- Tax considerations — taxes or tax credits that may apply will affect revenue streams.

The financing mechanisms used for a project will affect the cost to generate electricity or provide LFG to the direct user. Factors such as project lifetime, loan periods, interest rates, taxes, discount rates, and down payment percentage all affect project cost and therefore the cost of generating the electricity or providing the LFG to the direct user. These costs account for the funds required to purchase and install the capital equipment (capital amortization costs) and, together with the O&M costs, constitute a more representative cost of producing electricity or providing LFG to a direct user. Project lifetime and loan periods indicate how long a project will be active, compared to the length of the payment period for the project. Interest rates and down payment percentage affect how much is needed to pay the lender (if a loan is used to pay for the project). The discount rate affects how much a bond must yield when due (if municipal bonds are issued to fund the project). Taxes will affect how much revenue is left to pay off the equity and provide the expected return (i.e., post-tax revenue). Depending on the developer's contract with the landfill, royalty costs may also apply if the developer does not own the gas.

A pro forma analysis will present the results of calculating measures of economic performance that are used to determine financial feasibility, such as:

- *Internal rate of return (IRR)* — Return on investment based on the total revenue from the project and construction grants, minus down payment. This is the project cash flow, and expresses a percent "yield" on investment in the project.
- *Net present value (NPV) at year of construction* — The value of the project at the first year that is equivalent to all the cash flows, based on the discount rate. This is how much money the project will cost over its lifetime, considering that the money could have been invested elsewhere and accrued interest.
- *NPV payback period* — This is the length of time (in years) required for the project to pay for itself. The shorter the time, the better.
- *Annual cash flow* — Total revenue from the project minus expenses, including O&M and capital amortization costs. Essentially the income the project generates in a year.

For a preliminary assessment, LFGcost will calculate several of these financial performance indicators, such as IRR, NPV, and NPV payback period. It will also provide a preliminary capital and O&M cost estimate for the project.

Table 4-3 summarizes results of the 3 MW internal combustion engine and direct-use case studies as an example of a preliminary analysis of economic feasibility. These cases assume the landfill does not have a gas collection and flaring system. While a municipal project may be more common, the private case illustrates a situation for a privately owned landfill, or where a private developer will develop a project at a municipal landfill. More variations and options for these case studies, as well as descriptions of the cases, are presented in Appendix 4-A (electricity projects) and Appendix 4-B (direct-use projects).

Table 4-3. Example Financial Performance Indicators for Projects Requiring a Collection and Flare System

Economic Performance Parameter	3 MW Engine Project (With Collection and Flaring System Costs)*		Direct-Use Project (5 Mile — With Collection and Flaring System Costs)*	
	Private**	Municipal†	Private**	Municipal†
Net present value‡	($3,508,256)	($2,898,667)	$476,674	$2,761,909
Internal rate of return	-7%	-5%	14%	24%
Net present value payback (years)	None		12	6
Capital costs‡	$7,631,513		$4,629,695	
O&M costs‡	$884,764		$408,089	

* For the 3 MW internal combustion engines, the electricity sale price is 6¢/kWh; for direct-use projects, the LFG price is $5/MMBtu.

** 20% down payment, 8% interest rate. See case named “Electricity 2” in Appendix 4-A for the internal combustion engine project and “Direct Use 2” in Appendix 4-B for the direct-use project.

† 20% down payment, 80% municipal bond, 6% discount rate. See case named “Electricity 9” in Appendix 4-A for the internal combustion engine project and “Direct Use 8” in Appendix 4-B for the direct-use project.

‡ 2010 dollars.

Based on these results, the direct-use project is an attractive option and may be worth further consideration. The engine project, however, is not viable based solely on typical revenues from electricity sales. In this case, though, the project may qualify for various greenhouse gas credit programs, as it involves the installation of a new methane collection system and the subsequent destruction of that methane. If the collection system was installed voluntarily and meets other criteria, the additional revenues available from greenhouse gas credits may significantly improve the economic prospects of this project.

For illustration, applying a $4/metric ton carbon dioxide equivalent credit to this engine project would yield an additional $608,800 per year on average, which would result in $9,132,300 in additional revenue over the 15-year life of the project. This credit brings the IRR for the private 3 MW internal combustion engine project up to 10 percent from a negative value. Therefore, considering the available incentives, credits, or market revenues that a project may qualify for will be an important part of an economic analysis. See the case study named “Electricity 4” in Appendix 4-A for details on the financial results of this scenario.

Alternatively, the project might be able to take advantage of green pricing or other incentive programs. For example, if the electricity sales revenue could be increased to 8.76¢/kWh instead of 6¢/kWh (e.g., through a green power program or sale of RECs), then the IRR for the private case would increase to 10 percent. See the case study named “Electricity 3” in Appendix 4-A for more details on the financial results of this scenario.

LFG energy projects where a gas collection and flaring system is already in place realize improved economics because the collection system installation costs are not attributed to the energy project. Instead, the costs for gas collection are considered a sunk cost associated with other landfill operations, such as mitigating methane migration or controlling odors. However, such projects will generally not be eligible for credits for greenhouse gas capture if the gas collection and flaring was required by regulatory programs. Table 4-4 summarizes cases where a LFG collection and flaring system is in place.

Table 4-4. Example Financial Performance Indicators for Projects With a Collection and Flare System in Place

Economic Performance Parameter	3 MW Engine Project (Without Collection and Flaring System Costs)*		Direct-Use Project (5 Mile — Without Collection and Flaring System Costs)*	
	Private**	Municipal†	Private**	Municipal†
Net present value‡	$587,078	$3,303,608	$3,145,698	$7,501,924
Internal rate of return	14%	24%	57%	92%
Net present value payback (years)	12	7	3	2
Capital costs‡	$5,150,800		$2,779,773	
O&M costs‡	$526,317		$128,782	

* For the 3 MW engines, the electricity sale price is 6¢/kWh; for direct-use, the LFG price is $5/MMBtu.

** 20% down payment, 8% interest rate. See case named “Electricity 1” in Appendix 4-A for the engine project and “Direct Use 1” in Appendix 4-B for the direct-use project.

† 20% down payment, 80% municipal bond, 6% discount rate. See case “Electricity 7” in Appendix 4-A for the engine project and “Direct Use 6” in Appendix 4-B for the direct-use project.

‡ 2010 dollars.

Here again, the direct-use projects appear more favorable, but finding a suitable end user within a reasonable distance is not always possible. The fact that none of these projects has the burden of installing a collection and flaring system makes each option viable. That notwithstanding, if additional revenues are added, such as premium pricing on electricity, then the internal combustion engine case becomes considerably more advantageous. For example, if a 2¢/kWh credit on top of the buy-back rate is applied, the IRR for the private 3 MW internal combustion engine project becomes 30 percent, with a payback of 5 years. (See the case study named “Electricity 5” in

Appendix 4-A for further details.) As noted earlier, one should consider all possible revenue streams when performing an economic evaluation.

Finally, it is important to bear the developer's objectives in mind. Often, municipalities do not expect the same IRR and payback periods as private entities. Corporations, on the other hand, usually have competing uses for their limited capital and prefer to invest in projects with the greatest IRR and to recover their capital investment in just a couple of years. The financial requirements of the parties involved in developing a project must be considered in determining economic feasibility and selecting financing mechanisms. A project at a publicly owned landfill that is not financially attractive to a project developer could still be implemented through self-development or partnering arrangements. See Chapters 5 and 6 for more information on project structures and project development options, and Section 4.5 of this chapter for more information about financing mechanisms.

4.4 Step 4: Compare All Economically Feasible Options and Select Winner(s)

After multiple project options are compared, some options may emerge as clearly uncompetitive and not worth further consideration; alternatively, there may be one option that is clearly the superior choice and warrants a more detailed investigation. It is most likely, however, that multiple energy project options are available, and it may be necessary to compare the economic analyses of each option and select the most promising option, bearing in mind any non-price factors.

A head-to-head economic comparison can be used to rank the financial performance of each option to select a winner. This comparison should incorporate several economic measures in the ranking, since no single measure can guarantee a project's economic success. For example, projects could be ranked based on the NPV after taxes, making sure that the IRR requirements are satisfied, or that the debt incurred to finance the project is within reach. It may turn out that the project with the highest IRR may also have high capital and O&M costs and may simply cost too much for the financing budget. If so, a lower IRR project that costs less (and is easier to finance) could be the best option.

At this point, important non-price factors that may impact the project but may not be quantifiable by the economic analysis should be considered, such as risk related to attainment of emissions limits or risk associated with technology. For example, the project might be located in a severe non-attainment area where stringent emission limits are in place, making it difficult and expensive to get a permit for a new combustion device. In this case, finding a direct user that could supplant some of their current fuel use with LFG might be a more viable project. Likewise, some project options may be based on more proven technologies and would incur lower risk than other, newer technologies, despite their having the potential for a greater return on investment. The risk involved may influence the financing available and could require a higher-interest loan.

4.5 Step 5: Assess Project Financing Options

Many financing options are available to landfills and project developers, including finding equity investors, using project finance, and issuing municipal bonds. This section describes common types of financing and some potential advantages and disadvantages of each.

What Lenders/Investors Tend to Look For

Typically, lenders and project investors look at the expected financial performance of the project to decide whether or not to lend or invest in the LFG energy project. The debt coverage ratio is an important measure that the lender/investor will want to see (in addition to the IRR and other financial performance indicators from the pro forma analysis). The debt coverage ratio is the ratio of a project's annual operating income (project revenue minus O&M costs) to the project's annual debt repayment requirement. Lenders usually expect the dept coverage ratio to be at least 1.3 to 1.5 to demonstrate that the project will be able to adequately meet debt payments.

The higher the risk associated with a project, the higher the return expected by lenders or investors. Risks vary by site and by project and may entail various components of the overall project, from availability of LFG to community acceptance. In many cases, however, risks can be mitigated with a well-thought-out project, strong financial pro forma, use of proven equipment vendors and operators, and a well-structured contract. Table 4-5 lists the various categories of risk that might be associated with a landfill project, and potential measures that can be taken to mitigate these risks.

Table 4-5. Addressing LFG Energy Project Risks

Risk Category	Risk Mitigation Measure
LFG availability	• Measure LFG flow from existing system • Hire expert to report on gas availability • Model gas production over time • Execute gas delivery contract/penalties with landfill owner • Provide for backup fuel if necessary
Construction	• Execute fixed-price turnkey projects • Include monetary penalties for missing schedule • Establish project acceptance standards, warranties
Equipment performance	• Select proven technology for proposed energy use • Design LFG treatment system to remove impurities, as necessary • Get performance guarantees, warranties from vendor • Include major equipment vendor as partner • Select qualified operator
Environmental planning	• Obtain permits before financing (air, water, building) • Plan for condensate disposal
Community acceptance	• Obtain zoning approvals • Demonstrate community support

Table 4-5. Addressing LFG Energy Project Risks

Risk Category	Risk Mitigation Measure
Power sales agreements (PSA)	• Have signed PSA with local utility • Match PSA pricing, escalation to project expenses • Include capacity, energy sales, and RECs in energy rate • Sufficient contract term to match debt repayment schedule • Confirm interconnection point, access, requirements • Include force majeure (act of God) provisions in PSA
Energy sales agreements (ESA)	• Signed ESA with energy customer • Fixed energy sales prices with escalation or market-based prices at sufficient levels to meet financial goals • Customer guarantees to purchase all energy delivered by project • Limit liability for interruptions, have backup
Financial performance	• Create financial pro forma • Calculate cash flows, debt coverage • Maintain working capital, reserve accounts • Budget for major equipment overhauls

Financing Approaches

Several possible approaches can be taken to financing the project, each of which is described briefly below. The approaches described here are not necessarily mutually exclusive; a mixture of different financing approaches may be available for a project and might be better suited to meeting specific financial goals. Contact financing consultants, developers, municipal/county staff who deal with bond financing, or LMOP Partners who developed similar LFG energy projects for additional information about financing approaches that have been successful in similar situations.

Private Equity Financing. This financing approach has been widely used in past LFG energy projects. It involves an investor who is willing to fund all or a portion of the project in return for a share of project ownership. Potential investors include some developers, equipment vendors, gas suppliers, industrial companies, and investment banks. For small projects without access to municipal bonds, private equity financing may be one of the few ways to obtain financing. Private equity financing has the advantages of lower transaction costs and usually the ability to move ahead faster than with other financing methods. However, this form of financing can be more expensive, and in addition to a portion of the cash flow, the investor might expect to receive benefits from providing finance, such as service contracts or equipment sales.

Project Finance. This is a popular method for financing private power projects. With this approach, lenders look to a project's projected revenues rather than the assets of the developer to ensure repayment. The developer, therefore, is able to retain ownership control of the project while still obtaining financing. Typically, the best sources for obtaining project financing are small investment capital companies, banks, law firms, or energy investment funds. The main disadvantages of project finance are high transaction costs and lender's high minimum investment threshold.

Municipal Bond Financing. In the case of municipally owned landfills and municipal end users, the local government might issue tax-preferred bonds to finance the LFG energy project. This approach is the most cost-effective way to finance a project, because the interest rate is often 1 or 2 percent below commercial debt interest rates, and can often be structured for long repayment periods. However, municipalities can face barriers to issuing bonds, such as private business use and securities limitations, public disclosure requirements, and high financial performance requirements. Check with the state or municipality in which the bond is issued to determine the terms for securing bond financing and the method for qualifying for the bond, and perhaps consult with a tax professional before deciding on whether tax-exempt or taxable bonds should be secured.

Direct Municipal Funding. This approach — possibly the lowest-cost financing available — uses the operating budget of the city, county, landfill authority, or other municipal government to fund the LFG energy project. It eliminates the need to obtain outside financing or project partners, and it avoids the delays caused from their project evaluation needs. Many municipalities, however, may not have sufficient budget to finance a project or may have many projects competing for scarce budget resources. Additionally, public approval may be required, which could add an additional layer of complication and potential delays.

Lease Financing. In this approach, the project owner/operator leases all or part of the LFG energy project assets. This arrangement usually allows the transfer of tax benefits or credits to an entity that can best make use of them. Lease arrangements can allow for the user to purchase the assets or extend the lease upon completion of the term of the lease. The benefit of lease financing is that it frees up capital funds of the owner/operator while allowing them control of the project. The disadvantages include complex accounting and liability issues, as well as loss of tax benefits to the project owner/operator.

Summary

LFG energy project development poses several risks and rewards. Landfill owners should keep detailed data records, be conservative on the energy potential from the landfill, carefully review pro forma statements, and assist the procurement process in any way possible; long delays from permits, public opposition, or financing can be a turn-off for investors. Project developers should allow for all parties to benefit from the project, conduct financial sensitivity analyses to accurately portray risks, and set conservative goals for project schedules, costs, and revenues. Successful project development requires that all parties work together to mitigate the project risks and ensure that they can survive with less-than-ideal project results.